PRICING ELECTRICITY IN DEVELOPING ECONOMIES: APEC EXPERIENCE

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Electricity Pricing in APEC Developing Economies: The APEC Experience

ABSTRACT

Rapid economic expansion in the Asia Pacific region over the 1980 and 1990 decades has led to significant demand growth for electricity. Resultantly, in much of the APEC region particularly in the developing economies, expansion of electricity infrastructure is now beyond the capability of governments and therein lies the inception of the independent power producers (IPPs) program in Asia.

Historically, electricity has been viewed as a national strategic asset best provided by a vertically-integrated monopoly usually owned and directly controlled by the state. This approach has now been largely rejected and has given way to a general consensus among policy makers, regulators, industry analysts and economists that the generation and to a lesser extent the retail elements of the electric supply industry would be more efficiently delivered by firms operating in freely competitive energy markets.

In many economies, particularly developing ones, the electricity sector has been used as an instrument of social policy. This takes various forms in subsidized tariffs for certain group of consumers, preferential use of subsidized indigenous fuel costs and maintaining state-owned utilities which serve as employment providers.

With the drive for efficiency and the need for market-oriented tariffs to attract investment of new generating capacity from IPPs, governments have begun initiating electricity reforms to incentivise private power development to support industrial and economic growth. When electricity reform is contemplated, it is difficult to maintain policies which result in severe market distortions. However, eliminating subsidies and allowing large numbers of electricity sectors workers to be laid off from state-owned utilities after introduction of competitive market structures have very real political and social repercussions.

This paper discusses the state of electricity reform in six APEC developing economies and provides a backdrop on how each of these economies balance the need to use electricity tariff as an instrument of social policy with the drive for efficiency and market-oriented electricity pricing. Of the six APEC developing economies examined, five are Asean economies; Indonesia, Malaysia, Philippines, Thailand and Vietnam and the sixth being China.

Pricing Electricity in Developing Economies: The APEC Experience

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Strong economic expansion in the Asia Pacific region over the 15 years prior to the 1997 Asian financial crisis has led to significant demand growth for electricity. In much of the APEC region particularly for APEC developing economies, demand growth has outstripped the capability of governments to fund electricity infrastructure rapidly enough to meet the surge in demand. Historically, electricity has been viewed as a national strategic asset best provided by a vertically-integrated monopoly owned and controlled by the state. This approach has now been rejected brought about by the lack of government's capability to finance new electricity infrastructure in developing economies and the drive for greater efficiency which can be better delivered by firms in a freely competitive energy market amongst developed economies.

Electricity as the purest form of energy is now the most pervasive energy source propelling the engines of growth in both the developed and developing economies of APEC. Its role has been increasingly important as major technology development in all sectors of the economy has its basis on electric power. As rightly pointed out by Rosenburg (1998), the dynamics of current technological development is likely to extend the present trend of rising electricity share of total energy which incorporates semiconductors, computers, telecommunications and information technologies. In addressing the electricity pricing regimes of APEC developing economies, it is necessary to establish the basis under which each developing economy formulates its electricity policy reforms in order to attract private capital and support for investment in energy infrastructure and fuel delivery systems.

A sound electricity pricing policy is fundamental in promoting sustainable development underscored by the triple objectives of improving energy efficiency, protecting the environment and ensuring investment for infrastructure of electricity supply. Electricity prices need to cover the costs of production and investments to satisfy the opportunity costs of energy suppliers. More recently, a growing awareness of environmental degradation has required energy suppliers to factor these external costs into the electricity prices, bringing new challenges to energy policy makers.

Electricity pricing mechanisms are typically complex and vary widely across the APEC region. Different economies have different regulatory systems, policy frameworks and different energy policy goals and objectives. In the APEC economies, energy policies commonly subsidize, cross-subsidize, impose import tariffs, taxes, levies as well as prescribing required standards and other regulations. Although such subsidies and tariffs on energy products are not high, the market distortions generated result in lower economic efficiency and misallocation of resources.

To ensure that electricity pricing facilitate improvements in energy efficiency, protect the environment and incentivize reinvestment in supply infrastructure, it is imperative that price distortions are minimized and that the principles of consistency, transparency, clarity and cost-effectiveness are promoted.

It is with this overriding theme that the APEC Energy Ministers at the 1996 Sydney meeting endorsed 14 non-binding energy principles and these principles are again reinforced in Okinawa in October 1998 when Energy Ministers "stressed the importance of promoting private sector participation in infrastructure development in those areas permitted by their respective legal frameworks and re-emphasized the need for a predictable, transparent institutional and regulatory framework to enhance the investment climate". A recent study by APERC (Asia Pacific Energy Research Center) on electricity reforms undertaken by individual APEC economies suggests that most APEC economies have followed the non-binding principles to a greater or lesser extent.

Electricity generation fuel mix continues to change in deregulated energy markets where competition favors the cheapest fuel or plants with low capital and operating costs. In a strictly commercial evaluation, the generation technology that delivers the lowest levelized electricity unit cost will be chosen. However, energy security, plant reliability, environmental considerations and indigenous fuel availability may drive governments to adopt policies of fuel and generation technology diversification.

In most of the APEC developing economies, the electricity sector has been used as an instrument of social policy which takes the forms of cross subsidy for certain groups of consumers, export-oriented industries, promotion of new energy sources such as renewables and state-owned entities serving as employment providers. When an urgent new planting is required, it is often considered politically expedient to sacrifice economic efficiency for other policy considerations such as job creation and dissemination of infrastructure services to the poorer communities. When economic reform becomes necessary post the Asian financial crisis, governments find it difficult to maintain policies which result in severe market distortions. However, eliminating subsidies and laying off large numbers of electricity sector workers after the introduction of competitive market structures have very real political and social repercussions and such actions must be considered carefully. A balanced approach is taken by most APEC developing economies which comprises in most parts the staged phasing out of subsidies over a period of time as new privately funded plants are put into service.

A thorough understanding of the pricing mechanism is more critical in energy markets due to the high capital intensity and long lead times associated with electricity supply infrastructure. The essential nature of the service that electricity provides to all sectors of the economy requires that electricity prices are set prudently and efficiently. If electricity prices are held below the cost of production, it can result in negative results in terms of over-consumption, environmental degradation and wasted natural resources. Conversely, if prices are held artificially high, industrial competitiveness will suffer and some consumers may be deprived of an essential service.

The discussion below covers six APEC developing economies, five in the Asean region (Indonesia, Malaysia, Philippines, Thailand and Vietnam) and China to provide a comparative study of how policies particularly on electricity pricing have underpinned the different state of development in the electricity sector for each of these economies.

China

The electricity supply industry in China has developed rapidly over the 1990 decade recording an average annual growth rate of 8 to 9 percent. China's current installed electricity generation capacity exceeds 250,000 MW, second only to that of the United States. According to statistics released by the State Power Corporation, over 1,300 TWh of electricity was produced in 2000 representing over 70% of final energy consumption. Over 82% of electricity generation is from thermal plants (of which 86% are coal-fired), 17% hydropower and balance 1% from nuclear. The industrial sector is the primary consuming sector accounting for 71% of total power consumption, followed by residential with 14%, agriculture 6% and government/others 9%.

Although electricity growth has slowed, China economy appears to have weathered the worst effects of the Asian financial crisis and is now on a 7-8% GDP growth path on the back of its ascension to the WTO and hosting of the 2008 Summer Olympics. Accordingly, China is expected to add more generating capacity than any other economy averaging 15-17 GW each year.

During the 9th Five Year Plan from 1996-2000, China has set aside US$100 billion for priority development of electricity infrastructure with the funds divided equally between power stations and transmission lines. It is expected that 40% of the funds will come from the Central government, about 40% from local and city governments and about 20% from private (local and foreign sources). With such a major program, power supply shortages which was a major problem in the past has diminished with new power supplies coming on-stream, increased interconnection between provincial and city grids and conservation efforts. Some regions including the Shanghai region and most of the Guangdong province in fact face temporary oversupply problems. However, some provinces particularly the poorer inland provinces still face supply shortages. In some regions, the gap between peak and off-peak loads is increasing and power supply shortages are growing more serious during peak load periods. The main problem is inefficient distribution and unstable load due to the lack of an integrated national transmission system.

China has now six large grids and several provincial grids with 567,000 kilometers of transmission lines. The creation of a national grid is a major objective for the 2000 decade. This is to be achieved with the construction of the Three Gorges Power Station which will provide power for areas in Central and North China and the Sichuan grids and help to form the Great China Power Grid spanning a distance of 2,000 kilometers from east to west. The Three Gorges Power Station is expected to be completed by 2009 providing 17,000 MW capacity (only one year growth in China's electricity generation capacity) and a 5,000 kilometer transmission project connecting the power grids in Central and North China to the Sichuan province will be established.

The nature and structure of electricity retail tariffs is governed by Article 41 of the 1997 Power Law which permits the grid to charge different tariffs according to the type of user and according to whether it is a peak or non-peak period. It is a requirement of the law that users within the same grid using the same voltage of power must be charged the same rate. Article 42 requires retail tariffs to be approved by the State Pricing Bureau. Article 50 states that tariffs used for agriculture must be calculated in accordance with the principle of breaking even and earning a minimal profit.

The retail tariff takes into account of (1) wholesale tariff; (2) grid management fee; and (3) other fees and taxes including contribution to the Three Gorges Construction Fund. For example, the Shanghai Municipal Power Corporation has an average retail tariff of RMB 0.60 in 1999. Of this, RMB 0.13-RMB 0.14 represented various taxes including the Three Gorges Construction Fund, RMB 0.40-RMB 0.42 for wholesale tariff and RMB 0.04-RMB 0.07 for grid management fee. IPPs sells their generated electricity to the grid operated by provincial and city power bureaus at the wholesale tariff price as prescribed by the terms of the PPAs. In past IPPs, the offtaker would pay a cost-plus tariff that covered all fixed and variable costs including fuel costs. The current structure is for a negotiated base tariff adjusted for inflation, exchange rate fluctuations and fuel cost changes.

The current approach to PPAs is intended to facilitate transition to a competitive market. From December 1998, the central government issued a revised policy disallowing any guaranteed minimum offtake obligations or guaranteed tariffs with the aim of implementing an "open pool" market system in the near future. The new policy does not apply to IPPs with signed PPAs or those that have final approval from the State Development and Planning Commission. This will have a significant impact on all future IPPs as international lenders will be wary about investing in a project that does not have a predictable cashflow during the loan repayment period.

Malaysia

Malaysia is in the midst of an energy sector reform process. Prior to 1980, the National Electricity Board (NEB) was government-owned and supplied 80% of the total population of Malaysia. With its corporatisation in 1990 to become Tenaga Nasional Berhad, or TNB and partially privatized in 1992, the generation sector was opened to Independent Power Producers (IPPs) in 1994. Malaysia has developed a very successful IPP program based on a bankable Power Purchase Agreement (PPA) backed by an indigenous gas fuel supply arrangement making it possible for project financing in local currency. The financing in local currency is an Asian first, as power projects have hitherto been financed in US dollar. Such financing has been instrumental in the successful implementation of all the IPP projects as the depreciating Ringgit post the 1997 Asian financial crisis did not affect loan servicing capability since there is matching of revenue currency with costs. By 2000, the total installed generating capacity of the five IPPs reached 4,149 MW, all in gas-fueled gas turbine plants, achieving the targeted 30% participation of over 13,000 MW total installed capacity in Peninsular Malaysia. TNB continues to maintain dominance through control of most of the generating capacity, the transmission network and distribution system.

Under the current structure, almost 100% of the Peninsular population is supplied with electricity. This is achieved by having a tariff structure that allows TNB to cross subsidize the electricity price as indicated below.

Use	Household	Commercial	Industry	Streetlights	Overall
Rate (RM/kWh)	0.231	0.277	0.215	0.203	0.235
Share of total Sales (MWh)	8,516	13,177	24,515	358	46,466
Percentage (%)	18.3	28.4	52.8	0.5	100.0

The determination of the tariff is subject to the approval of the government based on the following considerations:

-Energy prices shall reflect the economic or true cost of supply;
-Adequate revenues to allow for the development of the power sector;
-Competitiveness of Malaysia's industries and services;
-Diversification of energy resources, with greater use of indigenous resources; and
-Aligned with social and economic objectives of the government.

Electricity demand growth has been rapid over the 1990 decade promoting the growth of inward direct investment by IPPs. Further reform is contemplated with the creation of a wholesale market and independent transmission ownership and operation. A new set of legal and regulatory frameworks has been prepared to pave the way for the establishment of an independent Energy Commission, a power pool system and an independent market operator. Despite these plans, Malaysia still pursues social policy goals by regulating the retail tariff of electricity in particular in striving to maintain a uniform tariff for all consumers.

Indonesia

Indonesia has installed electricity generating capacity estimated at 21.3 GW with 82% generation based on thermal, 15% from hydro and 3% from geothermal sources. Electricity is supplied by the vertically-integrated monopoly Perusahaan Letrik Negara (PLN), the state-owned energy corporation, which is also the monopoly provider of transmission , distribution and supply of electricity. It is the sole buyer and seller of electricity currently purchasing approximately 80% of the power produced by the IPPs.

The sharp decline in the GDP and devaluation of the Rupiah have significantly affected the financial standing of PLN. The fact that 60% of the PLN's costs (that is fuel purchases and debt repayments) are denominated in US dollars while revenues (exacerbated by subsidized tariffs) are earned in Rupiah has increased PLN's debt significantly. Additionally, the inclusion of take-or-pay provisions in the PPAs has meant payment obligations to IPPs (in US dollars) remain even though demand has decreased significantly.

Prior to the Asian financial crisis, Indonesia had plans for rapid expansion of power generation, to be achieved through opening up its power market to IPPs. IPPs provided a solution to serious shortage of electricity experienced in Indonesia between 1989 to 1991 due to the rapid growth of industry. The parties in large IPP projects were international energy companies (foreign investors) partnered with family or associates of former President Suharto. In early 1997, there were 39 IPP projects (totaling 30,072 MW) underway with a number of these projects having successfully secured debt financing. As a result of the Asian financial crisis, a number of IPP projects have been cancelled or "put on hold" and those projects which have secured financing or have been constructed or partly constructed are perceived to be in difficulty. There are now 26 IPP projects that have been signed involving about US$18 billion in investments and 24,751 MW of new capacity. All the 26 IPPs have entered into PPAs with PLN and the main characteristics of the PPAs include :

- tariff structure and tariff paths;
- electricity prices denominated in US$ (prices range from 5.7 US cents to 8.4 cents per kWh);
- take-or-pay obligation on PLN (under Paiton Energy's PPA, PLN is obligated to pay Paiton US$589 million per year if it does not use the electricity produced by Paiton);
- applicable law, generally governed by Indonesian law;
- arbitration clauses for disputes with reference to an international arbitration; and
- force majeure provisions.

Resulting in the failure of PLN to meet its payment obligations to the IPPs, the Indonesian Government has stepped in to ensure payment after some IPPs resort to arbitration. However, it is recognized and generally accepted by industry sources that a renegotiation of the PPAs will take place as this is essential for the successful restructuring of PLN, restore the government credibility with foreign investors and resolve the government budgetary shortfalls.

The price of electricity in Indonesia is set in Rupiahs and controlled by the government. Two separate tariffs are used to determine the selling price of electricity.

(1) Basic/Uniform Electricity Tariff
    This is determined pursuant to Presidential Decree No. 68/1994 and is based on the recommendation of the Minister of Mines and Energy.

(2) Periodic Electricity Tariff
This is determined by the Minister of Mines and Energy and can be adjusted once every three months for changes in the:
- price of electricity purchased by PLN;
- US dollar exchange rate to Rupiah;
- CPI s both foreign foreign and local ;
- fuel price; and
- tax regime and other government regulation (for example environmental provision).

The calculation of prices are broken down into the following components:

(1) Capacity charge-primarily the capital recovery charge comprising return for equity capital, debt repayment (both interest and principal), tax and depreciation and contract capacity and availability factor;

(2) Fixed operating cost and maintenance charge;

(3) Energy Charge-usually a pass-through cost component as determined by the quantity and type of fuel, specific heat rate and fuel price; and

(4) Variable operation and maintenance charge reflecting standby mode and plant availability as strategic reserve.

The tariff is set uniform across regions with cross subsidy between Java (which consumes 60% of the economy's electricity generated) and outside Java systems and among sectors. Largest subsidies are given to small residential consumers while large consumers pay market-oriented prices. Average end-user tariffs are well below the 5.7 –8.4 US cents that PLN pays to the IPPs. The shortfalls are being reduced with periodic phased tariff increases in accordance with IMF prescriptions.

Philippines

Two key players operate in the power sector, government-owned National Power Corporation (NAPOCOR) and privately owned utility, Manila Electric Company (MERALCO) providing about half of the electricity generated in the Philippines and the balance is handled by IPPs. MERALCO supplies the Manila and Metropolitan areas while NAPOCOR supplies the rest of the economy. NAPOCOR also controls the transmission system and distribution is handled by private electric utilities and rural electric cooperatives. The past and present government have been exerting efforts to reform the economy and the power sector is a priority area. Given the limited resources and the economy's growth and development objectives, the Philippine government has been paving the way for greater private sector capital investment and participation in the power sector.

The enactment of the Build-Operate-Transfer (BOT) law in 1987 marked the beginning of the private sector participation in major power projects and has resulted in substantial amount of IPP power capacity coming on-stream. The Foreign Investment Act now allows 100% foreign ownership in power generation projects. Government encouragement of immediate entry of IPPs in the early 1990s to end the severe power shortages, has resulted in higher tariffs under take-or-pay offtake provisions. The tariff is composed of demand and energy charges and includes foreign currency adjustments.

By end 2000, the total installed capacity reached 12,066 MW with 80% of the 75 million population electrified. Over 65% of the electricity produced come from thermal plants, 19% is based on hydro and 16% by geothermal. After the gas pipeline from Malampaya gas fields is linked to Batangas, south of Manila in late 2001, over 2,700 MW of new gas-fired combined cycle generating plants are planned for commissioning in 2002 and 2003. As in the other Asean economies, there are cross-subsidies between MERALCO customers from commercial (highest), to industrial and residential (lowest) and between NAPOCOR customers from MERALCO to small utilities and non utilities. Also, tariffs are different between grids with the highest in Luzon, to Visayas, Mindanao and small offshore islands (lowest). MERALCO maintains a residential rate of 3.12 pesos per kWh versus a service cost of 3.9 pesos while the rates for commercial and industrial users are set higher than its service costs.

MERALCO subsidizes residential and general service customers consuming no more that 300 kWh per month by charging the first 50 kWh of their monthly consumption 50% of the purchased power cost.

The Energy Regulatory Board (ERB), is the rate setting government agency in relation to NAPOCOR, IPPs, rural electric cooperatives and municipal, city and provincial distribution systems. AS NAPOCOR controls the generation and transmission functions for the economy's energy supply, the rates are bundled. Prices are not transparent; generation charges are not separated from transmission charges; neither is demand from energy, nor distribution line services from sale services. Rates contain many subsidies at both retail and wholesale levels. Tariffs do not generally reflect the true cost of production with subsidies at the grid and end-user levels. NAPOCOR's structure which is both horizontally and vertically integrated is not seen as adequate to provide incentives for efficiency and competition. In addition, in the distribution subsector, power losses are high and the large number of fragmented and small rural electrification cooperatives results in the absence of economies of scale, inefficient operations and high distribution overheads. Resultantly, the Philippine power rates is now the second highest in the region after Japan.

Thailand

Following the 1992 government announcement for greater private sector participation in the generation sector of the electricity industry, the state-owned electricity company, Electricity Generating Authority of Thailand (EGAT) in 1994 launched an Independent Power Producers (IPP) program. IPP projects were incorporated into EGAT's Power Development Plan which allows the private sector to construct, own and operate large power projects and sell the electricity to EGAT. The first solicitation for large IPPs calls for 5,800 MW to be commissioned in 2001 and 2002 and an additional 3,200 MW from Small Power Producers (SPPs defined as maximum of 90 MW each).

In response to slower growth projections post 1997, EGAT has scaled down the private power program and currently has signed agreements with six IPPs for 5,000 MW and 2,000 MW for the SPPs. The IPPs originally agreed to sell power to EGAT at prices denominated in Baht and following the Baht depreciation in July 1997, the projects were no longer viable as most of the IPPs costs and financing are in foreign currency. However, in September 1997, EGAT agreed to absorb most of the increased costs and agreed to raise the purchase price of electricity from the IPPs. To-date, two of the IPP projects have come on-stream with the balance to be commissioned by 2003.

The total economy's generating capacity is stated at over 21,000 MW (year 2001) with the peak demand of 19,000 MW resulting in a tight 10% spare capacity. If the 7,000 MW private power is fully implemented, the targeted 30% private power share will be achieved. Distribution and retail to end-users are handled by two government-owned entities; the Provincial Electricity Authority (PEA) and Metropolitan Electricity Authority (MEA) covering the provincial and metropolitan areas respectively.

The electricity industry is divided into the following sectors:

-generation entities: IPPs, SPPs and EGAT;
-transmission, power purchase and system operation: EGAT; and
-distribution and retail supply: PEA and MEA

While EGAT, IPPs and SPPs are all separate entities, there is no separation between generation, power purchase, transmission and system operation as EGAT is involved in all four functions. Whilst there is functional separation between EGAT and the distribution and retail sector, there appears to be no separation between the distribution and retail functions of PEA and MEA.

The retail electricity tariffs in Thailand are controlled by the National Energy Policy Office (NEPO) and require prior approval from the National Energy Policy Council and final acknowledgment from cabinet. Retail electricity tariffs are divided into seven groups as set out below:

-Residential: two categories, one below 150 kWh per month and one in excess of 150

kWh per month;
- Small general service: applicable to business, industrial, state enterprises, govt. institutions with a demand load less than 30 kW;
- Medium general service: as above but demand load between 30 kW and 2,000 kW;
- Large general service: as above with demand load exceeding 2,000 kW and pricing includes a Time Of Use (TOU) tariff for peak, partial and off peak period;
- Specific business service: applicable to electricity used for hotels, guesthouses or other lodging facilities with demand load exceeding 30 kW;
- Government institutions and non-profit organization: applicable to government institutions and NGOs with average consumption not exceeding 250,000 kWh per month; and
- Agricultural pumping service: applicable to government agricultural agencies, agricultural cooperatives and official farmer groups.

Tariffs to a large extent reflect the economic costs of supply and provide for a financial return and covers three main factors:

- to provide utilities with sufficient revenue requirements;
- to reflect marginal cost; and
- to serve certain social objectives particularly the support of the rural electrification program.

Under the existing retail tariff structure, the revenue required by the utilities is based on an 8% return on revalued asset and a minimum 25% equity financing. The overall tariff should cover almost 90% marginal cost. The main distortion in the retail tariff structure is the cross subsidy received by residential customers that use less than 150 kWh per month with the tariff targeted at 20% of marginal costs. Given that these customers are mainly in the PEA areas and the tariff structure is uniform throughout the economy, there exist a cross subsidy from MEA to PEA through the difference in the bulk supply tariffs which they buy from EGAT.

Three forms of retail tariff are used in Thailand:
- energy charges alone which apply to residential, small general service, government and agricultural pumping customers;
- energy plus demand charge which apply to medium and certain large general services; and
- TOU (Time Of Use) which applies to approximately 1,300 of the largest users whose demand exceeds 2,000 kW or whose energy consumption exceeds 355,000 kWh per month.

In 1992, the government put into place an Automatic Adjustment Mechanism, which adjusts the retail tariffs in line with changes in fuel costs and uncontrollable operating costs of the three utilities (including value added tax and cost associated with Demand Side Management).

Base electricity prices from EGAT to the MEA and PEA areas have not changed since January 1997 except for a surcharge of around 0.25 Baht/kWh for MEA and 0.12 Baht/kWh for PEA as well as a 10% VAT. Average electricity prices are currently around 1.9 Baht/kWh for Industrial and 2.3 Baht/kWh for Residential customers.

Vietnam

Electricity of Vietnam (EVN) is one of the five largest state-owned enterprises and comes under the Prime Minister's Office and Ministry of Industry. Since December 1998, EVN has increasingly expanded its electricity business to meet increasing demand of the economy. It operates seven distribution companies, four transmission companies, 13 power plants and an energy research institute. EVN is responsible for the economy's energy planning through the Institute of Energy.

Until recently, EVN has a monopoly on power projects. In 1999, the Prime Minister invited Vinacoal (state corporation responsible for the coal sector) and PetroVietnam (state corporation responsible for the oil and gas sector) to participate in power sector development. Vinacoal is permitted to build coal-fired power plants up to 1,200 MW while PetroVietnam can build gas-fired plants up to 1,000 MW. According to the EVN plan, Vietnam would have installed generation capacity of around 5,000 MW in 2000, between 12,000-14,000 MW in 2010 and 22,000-25,000 MW in 2020. Curreently, there are four IPPs in operation totaling 455 MW.

Electricity consumption and supply grew at a rapid pace along with economic development at rates of 18.2% and 17.6% respectively for the 1993-1997 period. Despite the 1997 financial crisis, it still chalked up a healthy growth rate of 15.9% for consumption and 13.1 % for production.

Electricity tariffs in Vietnam average 5.2 US cents/kWh and are based on the costs of production and distribution submitted by power companies to the State Pricing Committee (SPC). However, these tariffs underestimate real costs because fixed assets tend to be undervalued and depreciation rates are too low to reflect amortization rates that would allow for the repayment of investments and the cost of capital. Rate structures and tariff rates are now the central focus of the EVN reform program. In 1999, EVN made an agreement with multilateral donors to increase electricity prices. Institutions like the World Bank and the Asian Development Bank have long argued that EVN could not pay off its ODA loans if it continues to charge electricity tariffs that do not meet the long run marginal costs.

EVN has begun to implement a plan to raise rates from 200 Dong/kWh (US$0.02) to more sustainable levels approaching 1,000 Dong/kWh (US$0.07) which is the long run marginal costs in 2001. Average electricity tariffs have been adjusted from 702 Dong/kWh (US$0.053) to 728 Dong/kWh (US$0.0521) from October 1999. EVN's agreement requires average rates to increase from 5.2 US cents to 6.2 US cents on 1 January 2000 and to 7 US cents on 1 January 2001.

Electricity prices in each category are uniform across Vietnam and controlled by the government. Price changes are evaluated by the SPC and approved by the National Assembly. Since a uniform electricity tariff is applied to all similar classes of customers purchasing similar quantities of electricity, differences in the cost of bulk power supply and the distribution costs among the seven distribution companies are not reflected in the tariff charged to customers. It appears the government subsidizes certain customer classes. In addition, the time-of-use periods (peak, off-peak and regular periods) are also used in the current electricity tariff.

The government is rationalizing regulation of electricity pricing and is focusing on improving the following areas:

- Retail tariff structure should reflect seasonal factors; particularly as the economy relies heavily on hydropower sources of supply;
- The average retail price should be raised to the long run marginal cost; and
- The differences in metering and billing costs as well as their regulation should be considered together with changing tariff.

With the current structure, EVN covers mainly power generation and all activities of transmission and distribution through its subsidiaries. For electricity tariff setting, EVN submits a tariff revision proposal to the Ministry of Industry, SPC for final approval by the National Assembly. The current tariff reflects subsidy from the government and cross subsidy for all customer classes.

Conclusions

The APEC developing economies under review by and large have adopted the “best practice” IPP Principles endorsed by APEC Energy Ministers in 1996. The Principles were intended to address “critical success factors” necessary for successful IPP outcomes and include transparency, predictability, risk reduction and promotion of competition. Due to financial constraints and drive for transparency and efficiency, the government-owned, vertically integrated utility has accepted the role of IPPs which in most instances are still limited to being a generator, selling electricity into the grid with the state-owned utilities as the sole buyer who is also the owner of the transmission and distribution infrastructure.

Most economies including the APEC developing economies are accepting the view that the introduction of competitive markets is an essential aspect of achieving a stable and efficient electricity supply sector. Thus, in general, those IPP Principles that deal with market restructuring and reform such as changes to legislative and regulatory framework and endorsing tariff structures that promote competition, have taken greater importance in most economies’ electricity reform plan.

Since the onset of the 1997 financial crisis and the introduction of competitive pool pricing concept exposing IPP projects to more market risk while moving away from rigid PPAs that “lock-in’ generators and customers, few IPPs have reached financial close in the economies under study. The challenge for state-owned utilities negotiating projects is to build in flexibility into the PPA so as to prevent the utility tied to buying power at a price that becomes uncompetitive as markets evolve whilst ensuring that the project remains “bankable”.

Most of the six economies in this study are in the middle of or at least are actively engaged in considering the implementation of very significant reforms and restructuring of their electricity sectors. This is an extremely complex, lengthy and dynamic process, impacting on both the existing and future IPPs. Both the current status and assessment of future reforms in many economies are uncertain being subject to a variety of political and other socio-economic factors that cannot be determined. The development and implementation of policies affecting the electricity sector is to a large extent interrelated with policies in other sectors and over the economy as a whole. The IPP Principles express ultimate economic objectives and the manner in which an economy seeks to pursue these objectives depends on how it balances that objective with other policy objectives. Since these concerns vary widely from economy to economy, the implementation of the objectives expressed in the IPP Principles will take varying forms in the various member economies.

For a number of reasons, the surveyed economies demonstrate that fulfillment of the IPP Principles raises extremely complex issues. Firstly, Governments are faced with competing objectives and they have to weigh the objectives expressed in the IPP Principles against other competing concerns when formulating policy. Secondly, the Principles themselves involve to some degree conflicting objectives. The most important example is the tension between seeking broader competitive reforms and conferring predictability of cashflow for project financing.

However, the IPP Principles contain many important best practice mechanisms and processes that are applicable across the range of circumstances which can effectively assist the transition from a “lock-in” PPA with a predictable cashflow to an open pool concept which promotes efficiency and competition.